

BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

IN THE MATTER OF:

Application of Duke Energy Progress,
LLC for Adjustments in Electric Rate
Schedules and Tariffs and Request for
an Accounting Order

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DOCKET NO. 2018-318-E

Direct Testimony

of

BILLIE S. LACONTE

On Behalf of

Nucor Steel – South Carolina

March 4, 2019



IN THE MATTER OF:)	DIRECT TESTIMONY OF
)	
Application of Duke Energy Progress,)	BILLIE S. LACONTE FOR
LLC for Adjustments in Electric Rate)	
Schedules and Tariffs and Request for)	NUCOR STEEL – SOUTH CAROLINA
an Accounting Order)	

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GLOSSARY OF ACRONYMS

Term	Definition
ADIT	Accumulated Deferred Income Taxes
ARAM	Average Rate Assumption Method
CCR	Coal Combustion Residuals
COLA	Combined Operating License Application
DEP	Duke Energy Progress, LLC
DERP	Distributed Energy Resources Program
EDIT	Excess Deferred Income Taxes
EDIT Rider	Excess Deferred Income Tax Rider
Fukushima	Fukushima Daiichi Nuclear Power Station
IRP	Integrated Resource Plan
LGS	Large General Service
Nucor	Nucor Steel – South Carolina
PTY	Post-Test Year
ROE	Return on Equity
S&P	Standard and Poor's
TCJA	Tax Cuts and Jobs Act
TOU	Time-of-Use

Direct Testimony of Billie S. LaConte**1. INTRODUCTION, QUALIFICATIONS AND SUMMARY**

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. Billie S. LaConte; 12647 Olive Blvd., Suite 585; St. Louis, Mo., 63141.

3 **Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

4 A. I am an energy advisor and Associate Consultant at J. Pollock, Incorporated (J. Pollock)

5 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

6 A. I have a Bachelor of Arts degree in Mathematics from Boston University and a master's
7 degree in Business Administration from Washington University. Upon graduation in
8 May 1995, I joined Drazen Consulting Group, Inc. (DCGI). I joined J. Pollock in May
9 2015.

10 During my tenure at DCGI as well as my current position with J. Pollock, my
11 work has focused on ratemaking issues such as revenue requirement, cost allocation,
12 rate design, sales and price forecasts, power cost forecasting, electric restructuring
13 issues, cost of capital (return on equity) issues and contract interpretation. I have been
14 engaged in a wide range of consulting assignments including energy and regulatory
15 matters in both the United States and several Canadian provinces. This included
16 advising clients on economic and strategic issues concerning the natural gas pipeline,
17 oil pipeline, electric, waste water and water industries.

18 I have testified before the Missouri Public Service Commission, the Alberta
19 Energy and Utilities Board, the Arkansas Public Service Commission, the Iowa Utilities
20 Board, the Michigan Public Service Commission, the St. Louis Metropolitan Sewer

**1. Introduction, Qualifications
and Summary**

District Commission, the New Mexico Public Regulations Commission, and the Nova Scotia Utility and Review Board.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Nucor Steel – South Carolina (Nucor).

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I will discuss several of DEP's proposals, including:

- The Excess Deferred Income Tax Rider (EDIT Rider);
- Post-test year (PTY) adjustments;
- Amortization of coal ash expense;
- End-of-life nuclear costs;
- Amortization of other regulatory assets; and
- DEP's proposed return on equity (ROE) and equity ratio.

Q. DOES THE FACT THAT YOU OR THE OTHER NUCOR WITNESSES ARE NOT ADDRESSING EVERY POTENTIAL ISSUE IN THIS PROCEEDING IN ANY WAY IMPLY YOUR ACCEPTANCE OF DEP'S PROPOSAL?

A. No.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring **LaConte Exhibits 1** through **8**. These exhibits were prepared by me or under my direction and supervision.

Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are as follows:

- DEP's proposed EDIT Rider should be modified to return excess deferred taxes more quickly, which would result in an increase in the refund to at least \$26.6 million during the first year. My proposed modifications include:
 - amortizing and returning all unprotected plant-related excess deferred income taxes over 5 years,
 - amortizing and returning the deferred revenues over 2 years (my estimate does not reflect the return of additional deferred revenues for January – May 2019, which should also be returned promptly), and
 - removing the collection of the Distributed Energy Resources Program costs from the EDIT Rider.
- DEP has included \$169.6 million of post-test year plant additions, which is inconsistent with the Matching Principle. The post-test year plant additions increase DEP's revenue requirement by \$20.2 million. If the Commission allows DEP to include post-test year additions, then DEP should adjust its accumulated depreciation for all of its plant balances. This adjustment reduces DEP's revenue requirement by \$3.0 million.
- DEP should amortize its coal ash cost over 20 years and include only the expenses it incurred during the test year (\$24 million). This reduces DEP's revenue requirement by \$7.1 million. If the Commission allows DEP to include post-test year coal ash expense in this case, then it should collect only the costs incurred through December 2018, \$44.5 million, over 20 years. This reduces DEP's revenue requirement by \$5.0 million. To the degree the Commission determines that a portion of the coal ash expense should not be recovered in rates from consumers, such costs should be removed and the remaining coal ash costs should be amortized for recovery over 20 years.
- DEP should not be authorized to collect \$2.9 million per year for nuclear end-of-life costs. There are several uncertainties regarding these costs and DEP has indicated that it will seek subsequent license renewals to extend the life of its nuclear plants. The costs are speculative and it is premature for DEP to seek recovery of these costs.

- 1 • DEP proposes to amortize costs associated with the Harris Combined Operating
2 License Application (COLA) cost and Fukushima Daiichi Nuclear Power Station
3 (Fukushima) compliance costs over five years. The amortization periods should be
4 extended to match the lives of the related underlying assets. These adjustments
5 reduce DEP's revenue requirement by \$1.5 million.
- 6 • DEP's requested ROE is too high and should be reduced to: 1) recognize current
7 downward trends in authorized ROEs, 2) reflect the lower implied risk premium
8 and 3) recognize DEP's lower financial risk due to its above average common
9 equity ratio. The Commission should also consider reducing DEP's requested
10 common equity ratio to a level more in line with the common equity ratios of utilities
11 with similar credit ratings as DEP.

1. Introduction, Qualifications
and Summary

2. EXCESS DEFERRED INCOME TAX RIDER

Q. IS DEP PROPOSING TO RECOGNIZE THE IMPACT OF THE TAX CUTS AND JOBS ACT IN THIS CASE?

A. Yes. The Tax Cuts and Jobs Act (TCJA), which became effective on January 1, 2018, lowered the federal corporate income tax rate from 35% to 21%. Thus, DEP's income tax expense has decreased, which is reflected in the proposed rates. Furthermore, DEP has proposed an EDIT Rider to reflect the impact of the TCJA on the balance of DEP's accumulated deferred income taxes (ADIT). Through the EDIT Rider, DEP proposes to return to customers over time:

- protected and unprotected EDIT, and
- the over-collection of federal income taxes from January 1, 2018 – May 31, 2019 (referred to as "deferred revenue").

Q. HOW HAS THE TAX CUTS AND JOBS ACT AFFECTED DEP'S PROPOSED REVENUE REQUIREMENT?

A. The specific impacts of the TCJA on DEP's test-year revenue requirements include:

- Lower current and deferred federal income tax expenses.
- Lowering the tax "gross-up" factor used to translate a net operating income deficiency into a corresponding revenue deficiency or increase.
- Requiring DEP to: (1) revalue the ADIT balance, which was accumulated at the 35% pre-TCJA tax rate, at the current 21% tax rate, (2) place the EDIT in a regulatory liability account, and (3) return the EDIT to the customers that funded it in their past electricity bills.

Q. WHAT ARE THE COMPONENTS OF DEP'S PROPOSED EDIT RIDER?

A. Table 1 summarizes the components of DEP's proposed EDIT Rider.

2. Excess Deferred Income Tax Rider

Table 1¹ DEP Proposed EDIT Rider Balances and Amortization (\$000)			
Description	Amount	Annual Amortization	Amortization Period
Federal EDIT Protected	(\$146,798)	(5,432)	27+
Federal EDIT Unprotected Plant-Related	(58,254)	(2,913)	20
Federal EDIT Unprotected Non-Plant	(4,773)	(955)	5
Deferred Revenue²	(14,960)	(2,992)	5
DERP	12,668	2,534	5
NC EDIT	(1,140)	(1,140)	1
Total	(\$213,257)	(10,898)	
Adjusted for Return, Taxes & PSC Fee		(9,887)	

Included in the proposed Rider are the EDIT balances from the reduction in North Carolina's state income tax rate (*i.e.*, NC EDIT). DEP began to return the amounts to customers in its last rate case.³ DEP was granted permission to continue to record the amortization expense through no later than June 30, 2019.⁴ DEP also proposes that the tax refunds under the EDIT Rider would be offset by amortizing and recovering the

¹ Supplemental Direct Testimony of Laura Bateman, Updated Exhibit 3 at 1 and 2.

² The deferred revenue amount is for January 1, 2018, through December 31, 2018. The remaining deferred revenue for January 1, 2019, through May 31, 2019 is to be determined.

³ Direct Testimony of Laura Bateman at 33.

⁴ *Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Certain Capital and Operating Expenses*, Docket No. 2018-205-E, Order Approving the Deferment of Certain AMI Expenses, Depreciation Expenses, and the Amortization of Expenses Associated with North Carolina Excess Deferred Income Taxes at 3-4 (Aug. 9, 2018). Additionally, if new rates are in effect in this proceeding June 1, 2019, then the amortization would stop on May 31, 2019. The projected balance at that time is expected to be \$1.1 million (*supra* footnote 1).

2. Excess Deferred Income Tax Rider

1 regulatory asset created by DEP's Distributed Energy Resources Program (DERP),
2 specifically the solar rebate costs.

3 **Q. HOW MUCH IS DEP PROPOSING TO REFUND IN EXCESS INCOME TAXES?**

4 A. As proposed by DEP, the Rider would refund to customers both protected and
5 unprotected EDIT, as well as the over-collection of federal income taxes from January
6 1, 2018 – May 31, 2019, net of the DERP costs. If new customer rates in this
7 proceeding are effective June 1, 2019, then the NC EDIT amortization would stop on
8 May 31, 2019. The projected balance at that time is expected to be \$1.1 million and
9 would be refunded over one year.

10 If approved, DEP's proposal would refund approximately \$9.9 million during the
11 first year of the EDIT Rider, after carrying costs, SC License Tax and PSC Utility
12 Assessment Fee.

13 **Q. WHAT ARE ACCUMULATED DEFERRED INCOME TAXES?**

14 A. ADIT are income taxes that DEP has already collected in rates but has not yet paid to
15 the government. Thus, they represent ratepayer-supplied capital; that is, consumers
16 have already paid ADIT in their past electricity bills. Further, these future tax expenses
17 were accumulated on the assumption that the corporate federal income tax rate would
18 remain at 35%.

19 **Q. WHAT ARE EXCESS ACCUMULATED DEFERRED INCOME TAXES?**

20 A. EDIT are the portion of ADIT that DEP will not pay due to the reduction in the corporate
21 federal income tax rate from 35% to 21%. As a result, DEP recorded EDIT as a
22 regulatory liability. DEP has proposed the EDIT Rider, in part, as a vehicle to return
23 EDIT to customers.

2. Excess Deferred Income Tax Rider

1 **Q. OVER WHAT PERIOD IS DEP PROPOSING TO REFUND THE EDIT?**

2 A. DEP is proposing to refund all \$147 million of “protected” EDIT consistent with the
3 average rate assumption method (or ARAM). For DEP, the ARAM would result in
4 amortizing and returning protected EDIT over approximately 27 plus years.
5 Unprotected EDIT would be refunded over periods ranging from five to 20 years.
6 Specifically, \$4.8 million of unprotected non-plant EDIT would be amortized over five
7 years while \$58.3 million of unprotected, plant-related EDIT would be amortized over
8 20 years.

9 **Q. WHY AMORTIZE EDIT OVER DIFFERENT TIME PERIODS?**

10 A. The TCJA requires that the ARAM be used to refund EDIT that are designated as
11 “protected.” For DEP, the ARAM would result in amortizing protected EDIT over
12 approximately 27 plus years. The TCJA has no similar requirements applicable to a
13 utility’s EDIT that are designated “unprotected.” Thus, unprotected EDIT can be
14 refunded to customers over any period deemed reasonable by the Commission.

15 **Q. IS DEP’S PROPOSED TWENTY-YEAR AMORTIZATION OF THE UNPROTECTED**
16 **PLANT-RELATED EDIT BALANCE NECESSARY OR REASONABLE?**

17 A. No. First, a 20-year amortization is not required; absent a statutory requirement
18 otherwise (like the TCJA’s requirement for amortizing protected EDIT), customer
19 dollars should be returned reasonably promptly. Second, the TCJA is an extraordinary
20 once-in-a-generation change in the tax law — the last time a similar tax law change
21 was enacted was in 1986. Among the TCJA’s primary objectives is to put money back
22 into consumers’ pockets to encourage new investment, thereby helping the national
23 economy to grow at a faster pace. Returning unprotected EDIT over 20 years

2. Excess Deferred Income Tax Rider

1 undercuts this objective and is unnecessary. I recommend that all of the unprotected
2 EDIT be returned to customers more quickly -- over no more than 5 years (note that
3 DEP proposes to return only a small portion of this unprotected EDIT over 5 years).

4 EDIT was financed by DEP's customers and those customers are entitled to be
5 fully compensated for the excess income taxes they have previously paid. The majority
6 of the EDIT are protected. Thus, customers will have to wait more than 27 years to
7 receive their full benefit. Obviously, many customers that helped finance the current
8 protected EDIT will not be around at the end of 27-plus years. Particularly since this
9 protected EDIT cannot be passed back to customers any quicker, there is a compelling
10 reason to require DEP to refund the entirety of the unprotected EDIT balances,
11 including the amount related to plant, over as short a time period as reasonably
12 possible.

13 **Q. ARE YOU AWARE OF ANY OTHER UTILITIES THAT ARE CURRENTLY**
14 **REFUNDING UNPROTECTED EDIT TO THEIR RETAIL CUSTOMERS OVER VERY**
15 **SHORT TIME PERIODS?**

16 **A.** Yes. For example, Entergy Arkansas, Inc., is refunding \$466 million of unprotected
17 EDIT over a period ranging from 7 to 21 months.⁵ Similarly, Gulf Power Company
18 refunded \$69 million of unprotected EDIT during 2018.⁶

⁵ *In the Matter of the Application of Entergy Arkansas, Inc. for a Proposed Tariff Revision Regarding the Request for Approval of a Tax Adjustment Rider to Provide Tax Benefits to its Retail Customers*, Docket No. 18-014-TF, Order No. 2 at 3 (Mar. 27, 2018).

⁶ *In re: Stipulation and Settlement Agreement between Gulf Power Company and the Office of Public Counsel, the Florida Industrial Power Users Group, and the Southern Alliance for Clean Energy regarding the Tax Cuts and Jobs Act of 2017*, Docket No. 2018-0039-EI, Final Order Approving Joint Motion to Approve Stipulation and Settlement Agreement at 2 (Apr. 12, 2018).

2. Excess Deferred Income Tax Rider

1 **Q. WHAT IS THE DEFERRED REVENUE COMPONENT OF DEP'S EDIT RIDER?**

2 A. The \$15 million of deferred revenue represents the amount of taxes that DEP has over-
3 collected during the calendar year 2018. DEP proposes a five year amortization period
4 for the \$15 million of deferred revenue. DEP will also refund the deferred revenue
5 collected during the period January 1, 2019, through May 31, 2019. This amount is yet
6 to be determined.

7 **Q. DO YOU AGREE WITH THIS PROPOSED AMORTIZATION AND REFUND PERIOD**
8 **FOR THE DEFERRED REVENUE COMPONENT?**

9 A. No. The lower tax rate became effective on January 1, 2018. DEP could have
10 proposed to return the savings associated with the lower tax rate to customers much
11 sooner. For example, DEP could have proposed that a rider be put in place as of
12 January 1, 2018, or any time thereafter, that would have immediately reduced rates to
13 reflect the lower tax rate. Instead, DEP has continued to collect costs reflecting the
14 35% tax rate and deferred the over-collection as a regulatory liability. This deferred
15 revenue is ratepayer money that was paid to DEP over one year (and that customers
16 will continue to pay until new rates take effect), and there is no reason why DEP cannot
17 pay customers back their money over the same or a similar length of time. DEP's
18 proposal to amortize the deferred revenue over five years should be rejected. A two
19 year amortization period is much more consistent with giving the money back to those
20 customers who paid for it as quickly as possible.

2. Excess Deferred Income Tax Rider

1 **Q. PLEASE DESCRIBE DEP'S PROPOSAL TO RECOVER DERP COSTS IN THE EDIT**
2 **RIDER.**

3 A. DEP has included \$13 million of incremental DERP costs in the EDIT Rider, as an offset
4 to the lower tax benefits. These DERP costs are currently being recovered through
5 Rider 39.

6 **Q. SHOULD DEP RECOVER THE DERP COSTS IN THE PROPOSED EDIT RIDER?**

7 A. No. First, the DERP costs are a separate issue and should not be included in a rider
8 that is designed to refund excess deferred income taxes. The EDIT Rider should only
9 address items that are directly related to the lower income tax rate. Second, as stated
10 above, DEP is currently collecting these costs through its fuel cost rider and therefore
11 it is not necessary to include these costs in the EDIT Rider. Third, while I am not
12 offering a legal opinion, it appears that DEP's proposed treatment of DERP costs
13 through the EDIT Rider may be inconsistent with current South Carolina law and
14 regulatory policy.

15 **Q. PLEASE ELABORATE ON YOUR THIRD POINT.**

16 A. South Carolina law prescribes the treatment of incremental DERP costs, including
17 annual caps that DEP may not exceed when recovering those costs. Specifically, the
18 law states:

19 For the protection of consumers and to ensure that the cost of DER
20 programs do not exceed a reasonable threshold, the commission must
21 not approve a DER plan in which the total incremental costs to be
22 incurred by an electrical utility and recovered from the electrical utility's
23 South Carolina retail customer classes exceeds following annual
24 amounts per number of accounts for costs that are incurred on or after
25 January 1, 2104: residential: twelve dollars; commercial: one hundred
26 twenty dollars; and industrial: twelve hundred dollars. The application of
27 these caps to residential, commercial and industrial accounts will be as

2. Excess Deferred Income Tax Rider

1 set forth in the electrical utility's approved distributed energy resource
2 program.⁷

3 DEP's proposal to accelerate the recovery of DERP costs over five years, but then
4 offsetting those costs with income tax benefits via the EDIT Rider that would otherwise
5 go to reduce consumer rates, raises the question whether this approach is inconsistent
6 with this provision of South Carolina law governing the recovery of DERP costs.

7 **Q. HAS THE RECOVERY OF DERP COSTS BEEN FURTHER ADDRESSED IN CASES**
8 **BEFORE THE COMMISSION?**

9 A. Yes. In Docket No. 2014-246-E, the Commission approved a settlement agreement
10 setting forth a formula for calculating the "value of solar" under net metering that would
11 be used by each utility to determine DERP incentives. These incentives would be
12 recovered as an incremental cost of the DERP program – i.e., costs subject to the
13 statutory incremental cost cap. The settlement expiration date is January 1, 2021.
14 Related to DERP cost recovery, the settlement provides:

15 Utility cost recovery from customers related to net metering and DER
16 programs shall be reviewed and determined in each Utility's fuel cost
17 proceeding....if a general rate change is sought prior to the Settlement
18 Expiration Date, the general rate change shall not include DER Program
19 costs.⁸

20 **Q. HAS THE RECOVERY MECHANISM FOR RECOVERY OF EXCESS DERP COSTS**
21 **ABOVE THE CAPS BEEN SPECIFICALLY ADDRESSED BY THE COMMISSION?**

22 A. Yes. In Docket No. 2015-53-E, the Commission approved a mechanism for DEP for

⁷ S.C. Code Ann. § 58-39-150.

⁸ *In re: Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, Act No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189, Docket No. 2014-246-E, Order No. 2015-194, Exhibit 1 at 4, 6 (March 20, 2015).*

2. Excess Deferred Income Tax Rider

1 deferring and recovering incremental DERP costs that exceed the caps in a given year.
 2 Under this mechanism, DEP will follow and use deferral accounting and may carry
 3 forward the costs in excess of the caps to be allocated among customer classes
 4 consistent with the methodology for allocating variable environmental costs, for
 5 recovery in DEP's next fuel proceeding. DEP receives carrying costs calculated at the
 6 three-year Treasury note plus 65 basis points, and these costs will be treated as
 7 incremental DERP costs subject to the caps.⁹ The Commission found this mechanism
 8 to be reasonable, stating:

9 The proposed method will also ensure that the electrical utility is
 10 permitted to recover its reasonably and prudently incurred costs related
 11 to its approved DER program....the Settlement Agreement's terms
 12 provide stabilization of the rates, work towards minimizing fluctuations for
 13 the near future, and could incent economic development in South
 14 Carolina.¹⁰

15 **Q. WHAT DO YOU RECOMMEND?**

16 A. I recommend that the Commission modify DEP's proposed EDIT Rider. DEP's
 17 proposal uses unreasonably lengthy amortization periods to return unprotected EDIT
 18 and deferred revenue to consumers and inappropriately includes an offset to recover
 19 DERP costs. My specific recommendations are as follows:

- 20 • **Unprotected EDIT** – All unprotected EDIT (both plant related and non-plant
 21 related) should be amortized and returned to consumers over a period not to
 22 exceed five years. This adjustment increases the refund by \$8.7 million in the
 23 first year.
- 24 • **Deferred Revenue** – The deferred revenues representing the impact of the
 25 lower tax rates as of January 1, 2018, should be amortized and returned to

⁹ *In Re: Application of Duke Energy Progress, Incorporated to Establish a Distributed Energy Resource Program*, Docket No. 2015-53-E, Order No. 2015-514 at 19 (July 15, 2015).

¹⁰ *Id.* at 22.

2. Excess Deferred Income Tax Rider

consumers over two years. This adjustment increases the refund by \$4.5 million in the first year.

- **Treatment of DERP Costs** – DERP costs should be removed from the EDIT Rider and DEP should continue recovering those costs through Rider 39. This adjustment increases the refund by \$2.5 million in the first year.

The impact of my recommended adjustments to the EDIT Rider is summarized in Table 2.

Table 2 DEP Recommended EDIT Rider Balances and Amortization (\$000)			
Description	Amount	Annual Amortization	Amortization Period
Federal EDIT Protected	(\$146,798)	(5,432)	27+
Federal EDIT Unprotected Plant-Related	(58,254)	(11,651)	5
Federal EDIT Unprotected Non-Plant	(4,773)	(955)	5
Deferred Revenue¹¹	(14,960)	(7,480)	2
DERP	0	0	-
NC EDIT	(1,140)	(1,140)	1
Total	(\$225,925)	(26,656)	
Adjusted for Return, Taxes & PSC Fee		(\$26,591)	

Applying these adjustments would result in an annual refund of \$26.6 million during the first year of the rider (plus any impact from the January 2019 – May 2019 deferred revenues). The annual refund during the second year would be approximately \$23.6

¹¹ The deferred revenue amount is for January 1, 2018, through December 31, 2018. The remaining deferred revenue for January 1, 2019, through May 31, 2019, should be included in the Rider once it is determined.

2. Excess Deferred Income Tax Rider

1 million and would reduce accordingly in subsequent years to reflect the elimination of
2 the deferred revenue balance and the NC EDIT balance. The derivation of my
3 recommended EDIT Rider is provided in **LaConte Exhibit 1**.

2. Excess Deferred Income Tax Rider

3. POST-TEST YEAR PLANT ADJUSTMENT

1 **Q. WHAT IS A POST-TEST YEAR ADJUSTMENT?**

2 A. A post-test year adjustment restates test -year revenues and costs to recognize specific
3 asset additions and related costs that occurred after the close of a historical test year.

4 **Q. IS DEP PROPOSING ANY ADJUSTMENTS FOR PLANT ADDITIONS THAT WERE**
5 **PLACED INTO SERVICE AFTER THE TEST YEAR?**

6 A. Yes. DEP is proposing to include approximately \$169.6 million of plant additions that
7 were placed into service after the end of the test year in rate base in this proceeding.¹²
8 These plant additions reflect facilities that were placed in service by December 31,
9 2018. However, DEP is proposing to set rates using a calendar 2017 test year. Thus,
10 the proposed plant additions are properly characterized as “post-test year” adjustments.

11 **Q. HOW MUCH IS DEP’S POST-TEST YEAR PLANT ADDITION RELATIVE TO DEP’S**
12 **TEST YEAR PLANT IN SERVICE?**

13 A. The PTY plant additions by function are:

- 14 • Production: \$97.8 million;
- 15 • Transmission: \$17.5;
- 16 • Distribution: \$43.6; and
- 17 • General and intangible: \$10.8 million.

¹² DEP Corrected Supplemental Response to ORS 11th Audit Request, Item No. 11a (Jan. 17, 2019). In its Application, DEP proposed \$176.5 million of PTY plant additions.

None of the plant additions by function would exceed 6.4% of DEP's proposed rate base. Further, of the 57 individual projects comprising the PTY plant additions, the largest project is only 3.8% of DEP's rate base.

Q. DID DEP RECOGNIZE ANY ATTENDANT IMPACTS ASSOCIATED WITH THE PROPOSED \$169.6 MILLION OF POST-TEST YEAR PLANT ADJUSTMENTS?

A. Yes. DEP made corresponding adjustments to accumulated depreciation and depreciation expense to recognize the \$169.6 million of PTY plant additions. These attendant impacts are summarized in Table 3.

Table 3 Adjustments for Post-Test Year Additions to Plant-in-Service¹³ (\$000)	
Description	Amount
Depreciation & Amortization	\$5,323
General Taxes	\$1,063
Income Tax	(\$1,593)
Pre-Tax Return	\$15,387
Total	\$20,180

The total revised PTY adjustment of \$20.2 million is less than the original proposal of \$22 million due to the reduction in PTY additions (\$169.6 million vs. \$176.5 million).

Q. ARE POST-TEST YEAR ADJUSTMENTS CONSIDERED A REASONABLE RATEMAKING PRACTICE?

A. PTY adjustments are problematic. The purpose of a test year is to provide a consistent basis for determining the revenue requirement necessary to provide the utility with a

¹³ DEP Corrected Supplemental Response to ORS 11th Audit Request, Item No. 11a (Jan. 17, 2019).

3. Post-Test Year Plant Adjustment

reasonable opportunity to earn a reasonable return on the invested capital that is used and useful in providing electric service and to recover its reasonable and necessary expenses. While the choice of test year is supposed to result in data best suited to predict future costs and revenues, balancing the interests of the utility and ratepayers, in practice, the utility is generally free to choose the test year it wants (based on having all of the information). Having chosen the test year, all of the ratemaking components (*i.e.*, sales, revenues, expenses, net plant investment, and other rate base) should be set using the same assumptions. This is referred to as the Matching Principle. PTY adjustments, by contrast, allow the utility to pick and choose selective ratemaking components that it wants to adjust in order to improve upon the test year.

Q. WOULD DEP'S PROPOSED POST-TEST YEAR ADJUSTMENT BE INCONSISTENT WITH THE MATCHING PRINCIPLE?

A. Yes. The Matching Principle means using a consistent set of assumptions for all ratemaking components (*e.g.*, sales, revenues, invested capital and operating expenses). The fundamental premise behind the Matching Principle is the fact that rates are set as follows:

$$Rate = \frac{Adjusted\ Test\ Year\ Costs}{Adjusted\ Test\ Year\ Sales}$$

Thus, in order to set rates, the costs must be determined for the same test year as the corresponding sales. For example, if costs are based on a future period when sales are projected to be 10% higher, but sales are based on an historical test year, the utility would over-collect costs by 10%.

3. Post-Test Year Plant Adjustment

1 **Q. ARE THERE OTHER REASONS WHY YOU CONSIDER POST-TEST YEAR**
2 **ADJUSTMENTS PROBLEMATIC?**

3 A. Yes. PTY adjustments are also piecemeal ratemaking because they recognize only
4 one aspect of a utility's overall cost (*i.e.*, a plant addition) without also recognizing other
5 changes in costs that have occurred after the test year. The most obvious example is
6 with DEP's test year plant in service balance. There is no question that, since the close
7 of the test year, DEP has accumulated depreciation on its test year plant balance. Even
8 accounting for related capital additions, additional depreciation reduces net rate base.
9 This reduction in rate base, thus, would offset some of the impact of a PTY plant
10 addition.

11 Further, it is not always the case that a utility's revenue requirement is
12 increasing. While some expenses may increase, others may decrease. Similarly,
13 revenues can change as a result of customer additions and the corresponding increase
14 in energy sales and revenues. Higher revenues can offset increases in costs due to
15 plant additions and higher expenses.

16 Thus, a PTY adjustment without also accounting for changes in all other
17 revenues and expenses is problematic.

18 **Q. SHOULD DEP BE ALLOWED TO ADJUST ITS PLANT BALANCES TO**
19 **RECOGNIZE POST-TEST YEAR ADJUSTMENTS?**

20 A. Ideally, no. As stated above, a PTY adjustment is piecemeal ratemaking, and it violates
21 the Matching Principle. Accordingly, the best approach would be to not allow DEP's
22 proposed PTY adjustments.

3. Post-Test Year Plant Adjustment

1 Q. IF THE COMMISSION ALLOWS DEP TO INCLUDE POST-TEST YEAR PLANT
2 ADDITIONS IN RATE BASE, SHOULD IT ALSO REQUIRE OTHER
3 ADJUSTMENTS?

4 A. Yes. If the Commission allows DEP to include PTY plant additions, then DEP should
5 (at a minimum) also recognize PTY accumulated depreciation for its remaining plant.

6 Q. HAVE YOU QUANTIFIED THE ADDITIONAL ACCUMULATED DEPRECIATION
7 ASSOCIATED WITH DEP'S REMAINING TEST YEAR PLANT?

8 A. Yes. **LaConte Exhibit 2** calculates DEP's adjusted plant balance as of December 31,
9 2017, and calculates the depreciation expense for 2018. After accounting for
10 retirements, cost of removal and salvage, the adjustment to accumulated depreciation
11 is approximately \$32 million. Applying the pre-tax rate of return to this amount results
12 in a revenue requirement reduction of \$3.0 million.

13 Q. WHAT DO YOU RECOMMEND?

14 A. The Commission should consider not allowing DEP's proposed PTY adjustments.
15 However, if DEP is allowed to include PTY plant additions, then it should also be
16 required to recognize the additional year of accumulated depreciation for its test-year
17 plant balances.

3. Post-Test Year Plant Adjustment

4. COAL ASH POND CLOSURE EXPENSE

1 **Q. WHAT RECOVERY IS DEP REQUESTING REGARDING ITS COAL ASH**
2 **EXPENSE?**

3 A. DEP is requesting recovery of costs related to coal ash pond closures incurred from
4 July 2016 through September 2018 and estimated costs to be incurred October 2018
5 through December 2018.¹⁴ Specifically, DEP is seeking rapid recovery of \$46.5 million
6 of coal ash pond closure expense over a five year period, or an annual amortization
7 amount of \$9.3 million.¹⁵

8 **Q. IS THE \$46.5 MILLION ENTIRELY BASED ON THE TEST YEAR IN THIS**
9 **PROCEEDING?**

10 A. No. As shown on line 1 of **LaConte Exhibit 3**, the \$46.5 (col. 1) million figure includes
11 post-test year expenses of \$22.5 (col. 3) million through May 2019. Of this amount, \$2
12 million (col. 5) are projected return from January 2019 through May 2019. Thus, only
13 \$24 million (col. 2) of coal ash expense was incurred during the test year. As previously
14 stated, allowing post-test year costs is problematic in setting rates. This is particularly
15 true when we are addressing costs like coal ash that are subject to accounting deferral
16 and can be addressed in a future case. DEP's proposed coal ash expense through
17 2018 is \$44.5 million (col. 4).

¹⁴ Errata to the Direct Testimony of Jon F. Kerin at 6.

¹⁵ DEP Supplemental Response to ORS Audit 5-2.

1 **Q. DO YOU HAVE ANY OTHER CONCERNS WITH DEP'S PROPOSED RECOVERY**
2 **APPROACH FOR COAL ASH EXPENSE?**

3 A. Yes. DEP is using a different test year balance to determine the balance of the coal
4 ash expense it is proposing to recover in this case (*i.e.*, May 31, 2019) and the balance
5 of the coal ash expense it is currently authorized to recover (*i.e.*, December 31, 2017).
6 This is yet another example in which DEP violated the Matching Principle and is another
7 reason why PTY adjustments are problematic.

8 **Q. IS FIVE YEARS AN ACCEPTABLE TERM OVER WHICH TO AMORTIZE THE COAL**
9 **ASH EXPENSE?**

10 A. No. DEP's proposed five-year amortization period is unreasonable because it is far too
11 short. DEP has operated eight coal-fired generating facilities since the early 1950s. All
12 of these plants contributed to the coal ash basins over many decades. Due to the age
13 of these basins and the fact that coal ash has been accumulating for decades, the
14 amortization of the coal ash closure and removal expenses should more closely follow
15 the life span of a coal-fired generating plant.

16 **Q. WHAT DO YOU RECOMMEND?**

17 A. The average life span of DEP's coal-fired generation is approximately 55-60 years. I
18 propose that the coal ash expense for the test year (\$24 million) be amortized over at
19 least one-third of the life of a coal plant, or 20 years. This represents a fair recovery
20 period for these expenses and will not unduly burden current customers with costs that
21 are being incurred due to decades of coal-fired generation output. If the Commission
22 approves the PTY adjustment, then DEP should only include the additional expenses

4. Coal Ash Pond Closure Expense

1 that occurred through December 31, 2018, which are \$44.5 million. PTY expenses not
2 included in rates in this proceeding can be considered in a future proceeding.

3 **Q. WHAT IS THE EFFECT OF A LONGER AMORTIZATION PERIOD?**

4 A. A longer amortization period would reduce the cost included in the revenue requirement
5 related to the deferred coal ash costs, which will lower the rate increase to the benefit
6 of customers. DEP will still recover all the coal ash costs the Commission approves for
7 recovery, only over a longer period of time.

8 **Q. WHAT IS THE ANNUAL REVENUE REQUIREMENT USING YOUR PROPOSED 20**
9 **YEAR AMORTIZATION PERIOD?**

10 A. **LaConte Exhibit 3** shows the revised balance for amortization, \$24 million (through
11 December 2017), and the revised amortization period (20 years). It demonstrates that
12 these adjustments would reduce the annual amortization to \$1.2 million (col. 2, line 3),
13 from the proposed \$9.3 million (col. 1, line 3). The annual revenue requirement would
14 be reduced to \$2.5 million (col. 2, line 10) or \$7.1 million (col. 3, line 10) less than DEP's
15 proposed \$9.6 million (col. 1, line 10) revenue requirement adjustment.

16 If the Commission permits the PTY adjustment for the coal ash expense,
17 amortizing the revised amount of \$44.5 million over a 20 year amortization period would
18 reduce the annual amortization to \$2.2 million (col. 4, line 3). The annual revenue
19 requirement would be \$4.6 million (col. 4, line 10) or \$5.0 million (col. 5, line 10) less
20 than DEP's proposal.

21 It should be noted that the Nucor witnesses in this case are not taking a position
22 at this time on the reasonableness of the coal ash costs that DEP seeks to recover or

4. Coal Ash Pond Closure Expense

1 what amount of costs should ultimately be recoverable from South Carolina consumers.
2 To the extent DEP is permitted to recover only a portion of its proposed coal ash costs,
3 I would continue to recommend at least a 20 year amortization of the amount allowed
4 for recovery, but the calculation of the amortization would have to be revised
5 accordingly.

4. Coal Ash Pond Closure Expense

5. END-OF-LIFE NUCLEAR COSTS

1 **Q. WHAT ARE DEP'S PROPOSED END-OF-LIFE NUCLEAR COST ADJUSTMENTS?**

2 A. The end-of-life nuclear cost adjustments are adjustments to depreciation and
3 amortization expense to establish a reserve for end-of-life costs that DEP asserts it will
4 incur at its nuclear plants that are not captured in a decommissioning study and
5 reserves. As an example, it presents the write-off of materials and supplies in inventory
6 at the time of decommissioning that have little or no salvage value. DEP wants to
7 create a reserve to start accruing these end-of-life expenses for obsolete materials and
8 supplies. DEP is proposing an annual accrual amount in this proceeding of \$2.2 million
9 for its South Carolina retail jurisdiction.¹⁶

10 DEP also wants to create a reserve to start accruing for the expense related to
11 a portion of the last core of nuclear fuel in the reactor at the end-of-life of its nuclear
12 generating plants. The annual accrual amount for nuclear fuel is \$0.7 million for South
13 Carolina retail.¹⁷ The impact to operating income for these two end-of-life adjustments
14 is \$2.9 million.¹⁸

15 **Q. SHOULD THE COMMISSION ALLOW DEP TO RECOVER END-OF-LIFE COSTS AT**
16 **THIS TIME?**

17 A. No. The Commission should reject this proposed adjustment by DEP because the

¹⁶ Direct Testimony of Laura Bateman at 17-18.

¹⁷ *Id.*

¹⁸ DEP Corrected Supplemental Response to ORS 11th Audit Request, Item No. 11a (Jan. 17, 2019).

1 request is premature and the costs are purely speculative. DEP cannot know at this
2 time what materials and supplies will be obsolete when it retires its nuclear plants. Nor
3 can it accurately predict what portion of a fuel core will be remaining when it
4 decommissions its nuclear plants. The first plants to be decommissioned (Brunswick
5 Unit 2 and Robinson Unit 1) won't occur for at least 15 years, and DEP's most recent
6 integrated resource plan (IRP) indicates that DEP is actively exploring requesting
7 subsequent license renewals for its nuclear plants – in fact, DEP's base case under the
8 IRP assumes subsequent license renewals for DEP's existing nuclear generation to 80
9 years.¹⁹ I am also aware that several other utilities are seeking subsequent life
10 renewals from 60 to 80 years for their nuclear plants. These plants include Turkey
11 Point Units 3 and 4 (Florida Power and Light Company), Peach Bottom Units 2 and 3
12 (Exelon Generation Company) and Surry Units 1 and 2 (Virginia Electric and Power
13 Company).²⁰ Furthermore, DEP already has and will recover substantial costs from
14 ratepayers in anticipation of retirement of nuclear plants where there is no clear plan to
15 retire such plants. Any other hypothetical costs are better left for review and recovery
16 after-the-fact. Allowing DEP to recover and hold these costs so far in advance, will also
17 reduce DEP's incentive to minimize these costs. Because of the uncertainties
18 surrounding these costs and DEP's possible life extension renewals, it should not be
19 allowed premature recovery of additional nuclear end-of-life costs.

¹⁹ Duke Energy Progress South Carolina 2018 Integrated Resource Plan at 43-43.

²⁰ United States Nuclear Regulatory Commission, Status of Subsequent License Renewal Applications (Dec. 10, 2018). Link to site: <https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html>

5. End-of-Life Nuclear Costs

6. OTHER REGULATORY ASSETS

1 **Q. DO YOU HAVE ANY COMMENTS REGARDING OTHER REGULATORY ASSETS**
2 **THAT DEP IS SEEKING TO AMORTIZE AND RECOVER IN THIS PROCEEDING?**

3 A. Yes. I will specifically address two regulatory assets that DEP is seeking to recover
4 costs for: (1) the Harris Nuclear Units 2 and 3 Combined Operating License Application
5 (COLA) - \$6.7 million amortized over 5 years; and (2) the Fukushima Daiichi Nuclear
6 Power Station compliance costs - \$5.5 million amortized over five years.²¹ These
7 balances are as of December 31, 2017.

8 **Q. DO YOU AGREE WITH DEP'S PROPOSED AMORTIZATION PERIODS FOR THE**
9 **HARRIS COLA COSTS AND NUCLEAR COMPLIANCE COSTS?**

10 A. No. These costs should be recovered over the same time period as the underlying
11 asset life. This is consistent with generational equity. By accelerating the recovery of
12 the deferred costs over five years, rather than over the lifespan of the corresponding
13 assets, DEP's proposal creates generational inequity.

14 **Q. WHAT DO YOU MEAN BY GENERATIONAL EQUITY?**

15 A. Generational equity means that the costs of the facilities that are used and useful in
16 providing electricity service should, to the maximum extent possible, be recovered from
17 the customers that benefit from them. This is consistent with how utility assets are
18 depreciated. Specifically:

19 Depreciation accounting is a system of accounting which aims to
20 distribute cost or other basic value of tangible capital assets, less salvage
21 (if any), over the estimated useful life of the unit (which may be a group

²¹ Direct Testimony of Laura Bateman at 19.

1 of assets) in a systematic and rational manner. It is a process of
2 allocation, not of valuation. Depreciation for the year is the portion of the
3 total charge under such a system that is allocated to the year. Although
4 the allocation may properly take into account occurrences during the
5 year, it is not intended to be a measurement of the effect of all such
6 occurrences.²²

7 The deferred assets that DEP is seeking to recover are related to specific DEP nuclear
8 assets that are included in rate base. Thus, it makes sense from a policy perspective
9 to treat the deferred asset costs the same as the corresponding assets for ratemaking
10 purposes.

11 **Q. WHAT DO YOU RECOMMEND?**

12 A. The Commission should extend the amortization period to match the remaining lives of
13 the corresponding nuclear assets. **LaConte Exhibit 4** shows the impact of amortizing
14 the deferred cost of the Harris COLA over 48 years. This approach would cost
15 \$105,000, or \$903,000 less than DEP's proposal. **LaConte Exhibit 5** shows the impact
16 of amortizing the Fukushima costs over 38 years. This approach would cost \$542,000
17 and lower DEP's South Carolina revenue requirement by \$680,000.

²² National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* at 14 (Aug. 1996).

7. RETURN ON EQUITY AND EQUITY RATIO

1 **Q. WHAT IS DEP'S PROPOSED RETURN ON EQUITY?**

2 A. DEP has proposed a return on equity of 10.5%. DEP's ROE witness, Mr. Hevert,
3 recommended a 10.75% ROE, but DEP reduced it to 10.5% "...as a rate mitigation
4 measure, and in recognition that a rate increase may create hardship for some
5 customers..."²³

6 **Q. IS DEP'S PROPOSED INCREASE IN ROE OVERSTATED?**

7 A. Yes. DEP's proposed 10.5% ROE is excessive when looked at in the context of overall
8 industry trends. As can be seen in Table 4 below, the authorized ROEs for vertically
9 integrated electric utilities have been trending downward since 2010.

Table 4 Historical Authorized Return on Equity By State Regulatory Commissions In Rate Case Decisions Issues In the Years 2010 –Through 2018²⁴		
Year	All Electric Utilities	Vertically Integrated Utilities
2010	10.37%	10.42%
2011	10.29%	10.33%
2012	10.17%	10.10%
2013	10.03%	9.95%
2014	9.91%	9.94%
2015	9.85%	9.75%
2016	9.77%	9.77%
2017	9.74%	9.80%
2018	9.59%	9.68%

²³ Application at 13.

²⁴ S&P Global Market Intelligence RRA Regulatory Focus: Major Rate Case Decisions (Jan. 31, 2019).

7. Return on Equity and Equity Ratio

1 The average authorized ROE in 2018 for vertically integrated electric utilities was
2 9.68%, 82 basis points lower than DEP's proposal. The general downward trend over
3 the past several years is consistent with declining long-term interest rates (the risk-free
4 rate).

5 **Q. ARE THERE OTHERS REASONS WHY DEP'S PROPOSED ROE IS TOO HIGH?**

6 A. Yes. For example, the implied risk premium in DEP's proposal is overstated, which
7 results in an over-stated ROE.

8 **Q. PLEASE EXPLAIN.**

9 A. The risk premium is the premium over the risk-free rate that investors require if they
10 are going to invest in a riskier security. The implied risk-premium is estimated by
11 subtracting the risk-free rate from the ROE. DEP's ROE witness, Mr. Hevert, provides
12 a long-term forecast of the risk-free rate, 4.30%.²⁵ Subtracting this figure from the
13 10.5% ROE provides the implied risk premium, which is 6.20%. The average risk
14 premium (from January 1990 through October 2018) is 4.65%, or 155 basis points
15 lower than DEP's implied risk premium.²⁶ Therefore, DEP's implied risk premium is
16 overstated and inflates DEP's required ROE.

17 **Q. WHAT IS THE IMPACT ON DEP'S REVENUE REQUIREMENT IF ITS ROE IS SET**
18 **EQUAL TO THE NATIONAL AVERAGE AUTHORIZED ROE?**

19 A. Lowering DEP's ROE from 10.5% to 9.68% would reduce DEP's revenue requirement
20 by \$8.8 million. This is shown in **LaConte Exhibit 6**.

²⁵ Direct Testimony of Robert B. Hevert, Exhibit RBH-6 at 1.

²⁶ *Id.* at 32.

1 **Q. WHAT IS DEP'S PROPOSED COMMON EQUITY RATIO?**

2 A. DEP's proposed common equity ratio is 53%, which is significantly higher than the
3 average authorized common equity ratio in 2018 (48.95%). A thicker equity ratio lowers
4 a utility's financial risk. Lower financial risk equates to a lower ROE.

5 **Q. WHAT IS DEP'S CREDIT RATING?**

6 A. DEP's corporate long-term issuer rating from Standard and Poor's (S&P) is A-.²⁷

7 **Q. HOW DOES DEP'S PROPOSED EQUITY RATIO COMPARE WITH OTHER
8 ELECTRIC AND INVESTOR OWNED UTILITIES WITH SIMILAR CREDIT
9 RATINGS?**

10 A. The common equity-to-book capital ratio of electric investor-owned utilities with an S&P
11 rating of A- is 49.37%, as shown in **LaConte Exhibit 7**, which provides the common
12 equity ratio for electric investor-owned utilities with an S&P rating of A-. DEP's
13 proposed 53% equity ratio is clearly well above average.

14 **Q. DOES DEP'S HIGHER EQUITY RATIO AFFECT ITS FINANCIAL RISK?**

15 A. Yes. DEP's thick equity cushion significantly lowers its financial risk. Lower financial
16 risk implies a lower expected cost of capital or ROE. Investors' expected return for
17 DEP will be lower due to its lower risk, therefore the Commission should award DEP
18 with a lower than average return on equity if DEP is also granted a higher than average
19 equity ratio.

²⁷ S&P Global Market Intelligence, Duke Energy Progress, LLC – Credit Ratings.

1 **Q. PLEASE SUMMARIZE YOUR COMMENTS REGARDING DEP'S REQUESTED**
2 **RETURN ON EQUITY.**

3 A. DEP's requested 10.5% ROE is significantly inflated. It is significantly higher than the
4 national average authorized ROE of 9.68% in 2018. Furthermore, it overstates the
5 implied equity risk premium by 155 basis points. DEP would have lower financial risk
6 because of its proposed 53% common equity ratio, which is significantly above the
7 common equity ratio of utilities with similar credit ratings. For these reasons, the
8 Commission should award DEP with an ROE that is significantly lower than its
9 requested ROE of 10.5%. A lower ROE would allow DEP to remain financially sound
10 and attract new investors while balancing the interest of ratepayers in paying fair and
11 reasonable rates.

12 **Q. SHOULD THE COMMISSION CONSIDER LOWERING DEP'S REQUESTED**
13 **COMMON EQUITY RATIO?**

14 A. Yes. As noted above, DEP's proposed 53% common equity ratio is well above the
15 industry average. Since common equity returns are much higher than debt returns,
16 this high ratio costs ratepayers substantially. The Commission should consider
17 reducing DEP's equity ratio for ratemaking purposes. To illustrate the impact of this
18 issue, using the average 49.37% common equity ratio would reduce DEP's revenue
19 requirement by \$5.5 million. This is shown in **LaConte Exhibit 8**.

7. Return on Equity and Equity Ratio

8. CONCLUSION

Q. BASED ON YOUR RECOMMENDATIONS, WHAT FINDINGS SHOULD THE COMMISSION MAKE?

A. I recommend that the Commission adopt the following modifications to DEP's proposals and findings as to DEP's proposed revenue requirement:

- For the proposed EDIT Rider, amortize all unprotected EDIT over five years, amortize the deferred revenue over two years and completely remove the DERP expense from the Rider. This would make the amount of the credit in the EDIT Rider in the first year \$26.6 million instead of the \$9.9 million proposed by DEP. (The 2019 deferred revenue is not included in this calculation, but should also be included in the Rider once the figures are available.)
- Consider eliminating DEP's proposed PTY plant adjustments (a total of \$20.2 million of DEP's proposed revenue requirement). If the Commission allows a PTY adjustment for plant additions, then adjust accumulated depreciation for all of DEP's plant balances up to December 2018. This adjustment to accumulated depreciation would reduce revenue requirement by \$3.0 million.
- Amortize any coal ash expense found to be recoverable in this case over at least 20 years:
- Limit recovery in this case to coal ash expense for the test year and exclude PTY coal ash expense. Amortizing the remaining test year coal ash expense over 20 years reduces revenue requirement by \$7.1 million.
- In the alternative, if the Commission allows a PTY adjustment for coal ash, DEP should only be permitted to collect the costs incurred through December 2018. Amortizing this \$44.5 million over 20 years reduces the revenue requirement by \$5.0 million.
- Adjust amortization as necessary to reflect any disallowance by the Commission of coal ash expense.
- Reject DEP's proposed adjustment for end-of-life nuclear costs. This reduces revenue requirement by \$2.9 million.

8. Conclusion

- 1 • Extend the amortization period for the Harris COLA and the Fukushima
2 compliance costs to match the life of the underlying assets. This reduces
3 revenue requirement by \$1.6 million (Harris COLA: \$903,000; Fukushima:
4 \$680,000).
- 5 • Reduce DEP's requested cost of capital substantially:
- 6 • DEP's requested 10.5% ROE is too high. The Commission should consider an
7 ROE that is no higher than recently authorized ROEs for other vertically
8 integrated utilities and reflects the actual implied risk premium and DEP's
9 financial risk.
- 10 • DEP's equity ratio is also too high. The Commission should consider reducing
11 DEP's proposed equity ratio to a level more in line with equity ratios for utilities
12 with a similar credit rating as DEP.

13 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

14 A. Yes.